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The future of electricity generation in Australia: A case study of New South Wales

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ABSTRACT

The Australian electricity industry has found itself the subject of an intense political debate. At the center is the role of coal-fired generation. The most economic form of new generation technology in Australia is wind on a levelized cost of energy (LCOE) basis. However, new wind generation must be 'firmed' to address variability in output. The analysis in this article finds the optimal plant mix will need to be increasingly 'flexible' to complement variable renewables.

1. Introduction

Australia's National Electricity Market (NEM) is an energy-only gross wholesale pool. The operation of an energy-only market is well documented by Simshauser (2010). For such a market to be sustainable it must facilitate an "optimal mix" of generators recovering their fixed (capacity) and variable (fuel and operating) costs over the business cycle. Early studies of the NEM concluded that it had produced significant economic benefits (see Parer, 2002, as an example) despite concerns about revenue adequacy for generators (Simshauser, 2010).

From 2001 onwards, Australian policymakers introduced a number of often overlapping policies aimed at reducing greenhouse gas emissions and increasing the penetration of renewable energy. These included: the Mandatory Renewable Energy Target (MRET); the Large Scale Renewable Energy Target; Premium Feed-in Tariffs (FiT) for embedded generation; the NSW Greenhouse Gas Abatement Scheme; the Clean Energy Act (carbon pricing); the 13% (subsequently 18%) Queensland Gas-Fired Electricity Generation Scheme; and various capital subsidies for solar hot water and embedded solar PV generation. Nelson et al. (2010) provide an overview of the various types of climate change and renewable energy policies that have been introduced over the preceding two decades.

These climate change and renewable energy policies facilitated enormous investment in new generation capacity. Nelson et al. (2015) found that around 16 GW of new investment has been facilitated by climate change policies in Australia. But aging "firm dispatchable" capacity has been withdrawn from the NEM in significant quantities. As low short-run marginal cost (SRMC) renewable plant reduced wholesale prices, aging and inflexible (but firm and dispatchable) coal-fired plants have been retired, resulting in a sudden and dramatic upward shift in wholesale electricity prices.

A relatively unexplored but critical shortcoming of energy-only markets in a "high penetration" renewables system is the interaction with forward derivative markets. In "restructured" markets with retail competition, a liquid forward market is critical to facilitate price risk mitigation. As an intermittent energy source, renewables (excluding hydro) are unable to sell financial derivative products to retailers. As renewable grid penetration increases, an increasing proportion of the load is traded without price risk mitigation products in place. These issues are becoming apparent in high-renewable-penetration markets such as South Australia.

A blackout in South Australia on Sept. 28, 2016, resulted in the Australian Government initiating an inquiry into energy policy, led by Australia's Chief Scientist (Finkel et al., 2016). The review provided 50 recommendations to government. Arguably the two most important recommendations were the introduction of a "Clean Energy Target" and a "Generator Reliability Obligation." These two obligations were thought to deliver on the objectives of reliability, affordability, and reduced greenhouse emissions by incentivizing investment in low-emissions electricity supply and ensuring that participants in the market supported the forward derivatives market to ensure reliable supply and liquidity that facilitates ongoing retail market competition.

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In late 2017, the Commonwealth Government ruled out implementing the Clean Energy Target and instead developed the "National Energy Guarantee." This policy is effectively a "baseline and credit" scheme which would incentivize electricity retailers to source low-emissions generation to meet an emissions baseline consistent with Australia's international obligations articulated at COP21 in 2015, a 26–28% reduction in emissions by 2030 relative to 2005 levels. At the same time, retailers would also be required to demonstrate support for "reliability" by adequately contracting for "firming generation." It is thought that such a policy could facilitate the ambitious targets of Victorian and Queensland state governments, where policies to achieve 40% and 50% renewable energy penetration, by 2025 and 2030, respectively, have been set.

In the middle of all this has been an intense political debate about the Liddell power station in New South Wales. The owner, AGL Energy, announced in 2015 that the 2000 MW coal-fired power station would close in 2022 as a result of both its age and its emissions profile being inconsistent with the Commonwealth Government's commitment to playing its part in keeping global warming limited to 2 ° Celsius (AGL, 2015, 2016). A number of Commonwealth Members of Parliament (MPs) have stated that AGL is "shorting the market" and that it should be "forced to keep the power station operating" (ABC, 2017). AGL has committed to developing a "90 day plan" for investment in new capacity and energy equivalent to that required to meet any gaps caused by the closure of the Liddell power station.

The purpose of this article is to consider the most appropriate investment for new supply side infrastructure in the Australian market given: changing demand dynamics; technology costs; and the need to reduce greenhouse gas emissions. Section 2 articulates the different market dynamics of the U.S. and Australia as they relate to closure of coal-fired power stations. An overview of the New South Wales electricity market and changing electricity demand and technology costs is presented in Section 3. An "optimal plant mix" solution is modeled in Section 4 with other important considerations for investors evaluated in Section 5. Concluding remarks are provided in Section 6.

2. Disorderly exit of coal-fired power stations: a contrast with the U.S.

Australia has experienced a "disorderly" transition to renewables as existing aging coal-fired power stations have been closed. Prices were significantly below long-run average cost for many years due to oversupply created by flat underlying energy demand and new supply of renewable energy driven by climate change policies. Eventually, the economic pressure of relatively low wholesale electricity prices led to the disorderly withdrawal of significant quantities of capacity.[1] The closure of capacity is shown in Table 1.

Importantly, very little notice of closure was provided by any of the power station owners. In the case of Hazelwood, Northern and Playford, less than one year of notice was given. Unsurprisingly, forward contract electricity prices increased substantially. With such little notice of closure, there was no time for new generation to be built. Importantly, "firm dispatchable" capacity is still required to complement the significant penetration of wind generation within the Victorian and South Australian regions. The total closure of thermal capacity and investment in new renewable and gas-fired infrastructure is presented in Table 2. It is clear that investment in new "firm dispatchable" capacity has not kept pace with capacity withdrawals of aging coal-fired power stations since 2013.

Table 1
Power station closures in National Electricity Market.
Source: AEMO data.

State	Power station	Coal type	Commissioned	Closed	Capacity (MW)
NSW	Munmorah	Black	1969	2012	600
NSW	Redbank	Black	2001	2014	143
NSW	Wallerawang C	Black	1976	2014	1000
VIC	Morwell	Brown	1958	2014	189
VIC	Angelsea	Brown	1969	2015	160
QLD	Collinsville	Black	1968	2012	180
QLD	Swanbank B	Black	1970	2012	500
SA	Northern	Brown	1985	2016	546
SA	Playford	Brown	1960	2016	240
VIC	Hazelwood	Brown	1964	2017	1600

Table 2
New capacity and coal-fired capacity withdrawals in Australia.
Source: Simshauser (2017).

Year of Exit/Entry	Coal Retirements		Gas Plant Entry			Renewables Entry	
	No. of plant	Capacity (MW)	No. of plant	Total (MW)	CCGT[a] (MW)	No. of plant	Capacity (MW)
2005–2012	2	740	31	8674	2546	112	2640
2013 +	9	4656	4	218	52	49	2422
Total	11	5396	35	8892	2598	161	5062
Av. Age		42 years					

Coal-fired generation closure – 18% of fleet.
[a] CCGT column is a subset of the total gas capacity column.

It is not unusual for coal-fired power stations to be permanently closed when they are at an advanced age. Fig. 1 shows the age of coal-fired power stations operating globally. Very few power stations are operating beyond 50 years of age. Australia's experience, whereby around three-quarters of the thermal fleet is beyond its original design life (Nelson et al., 2015), is not too dissimilar from other comparable markets.

As a contrasting example, in the U.S. there have been similar closures of aging coal-fired power stations. However, there are two critical differences between the U.S. and Australia: the relatively stable policy environment in the U.S.; and the price and availability of natural gas since the turn of the decade. Australian investors have been reluctant to invest in new mid-merit gas-fired generation (such as combined-cycle turbines) due to both an inherently uncertain long-term energy and climate change policy and the significant changes that have occurred in domestic gas markets.

Australia's east-coast gas market has changed materially over the past decade. The development of new drilling technologies led to a significant increase in reserves from around 3400 PJ in 2005 to around 50,000 PJ today. This resulted in the construction of three large LNG export facilities in Queensland. There is more than enough gas to *physically* satisfy domestic demand and current LNG export contracts for at least 20 years. But the estimated marginal cost of production for these resources is around $6/GJ. Beyond around 50,000 PJ there is a significant step-change in estimated costs with a range of between $7/GJ and $9/GJ, reflected in Fig. 2. The same technological revolution that has unlocked low-cost shale gas resources in the U.S. has produced the perverse outcome in Australia whereby higher-cost gas resources (from coal-seam gas) set the marginal cost of gas utilized in gas-fired electricity generation infrastructure.

But in the U.S., access to low-cost shale gas has resulted in significant investments in new gas-fired capacity. The retirements of U.S.

[1] It is ironic that the 'merit-order effect' which has played a contributing role in the disorderly transition to renewables was at one time celebrated by some commentators as a way to permanently reduce prices. Felder (2011) demonstrated conclusively that in contrast to popular public perception, it is not welfare enhancing. Felder (2011, p. 34) sums up this apparent economic contradiction succinctly, '.if all electricity was provided by out-of-market technologies wholesale energy prices would be near zero, yet consumer electricity costs would increase to cover the additional costs of these technologies, thereby indicating that there was something amiss.' In other words, the 'merit-order effect' must be transitory in nature.

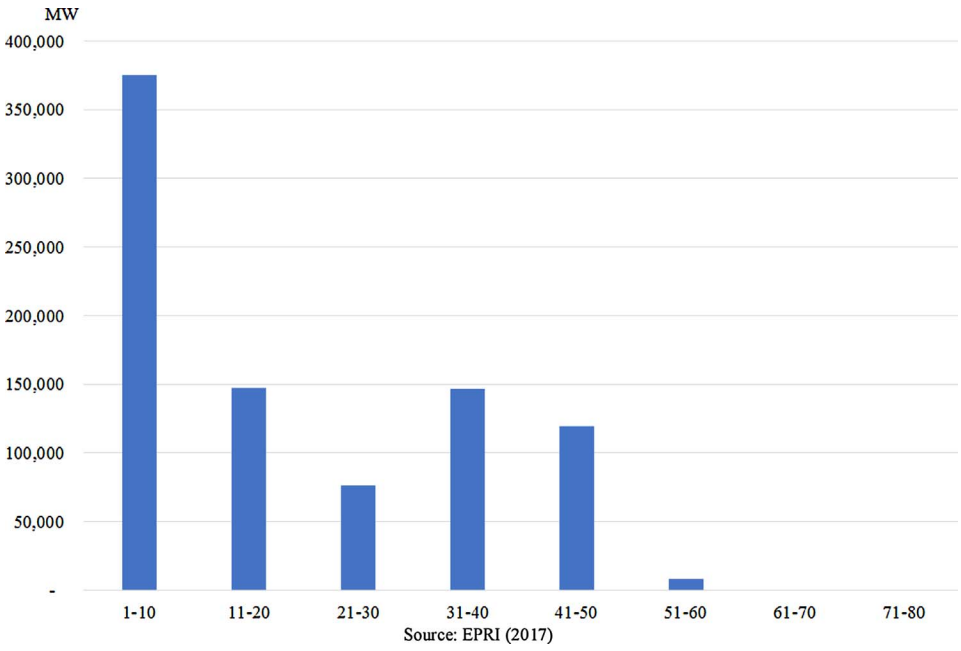

Fig. 1. Age of existing coal-fired power stations globally.
Source: EPRI (2017).

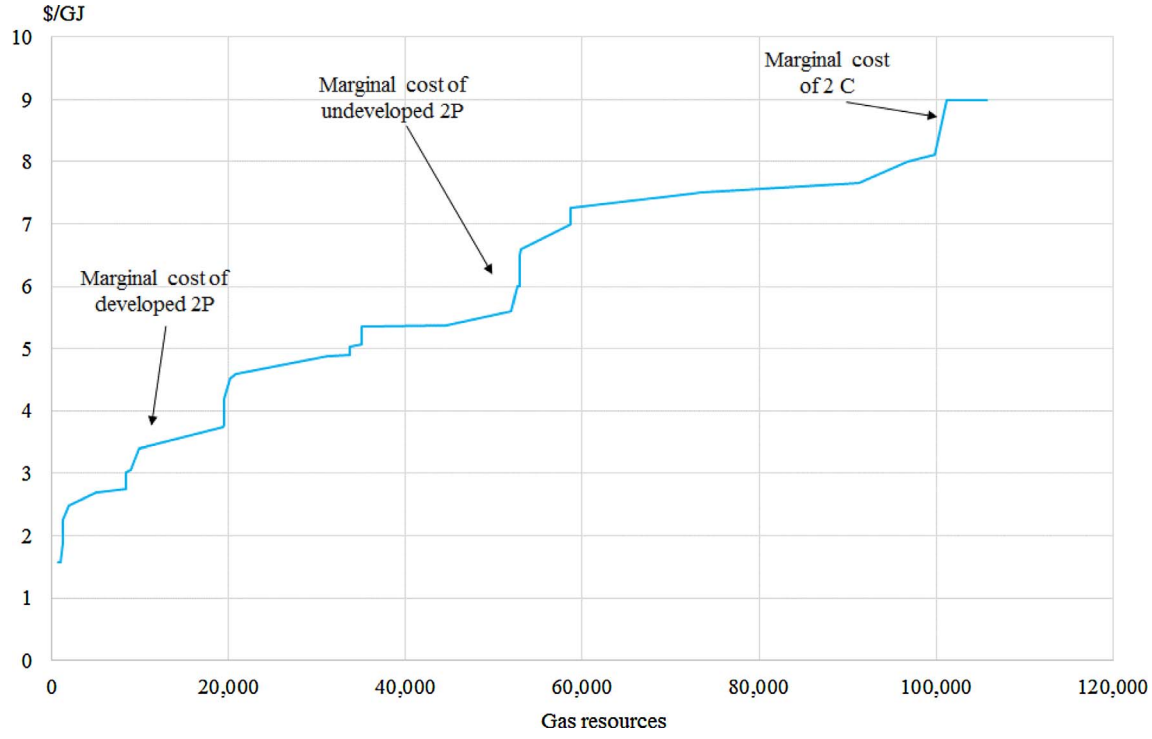

Fig. 2. Aggregate supply curve for east-coast Australian gas market.
Source: Adapted from AEMO (2017).

coal capacity and investment in new renewable and gas-fired capacity is presented in Table 3. It is evident that there has been more investment in new renewable and gas-fired capacity than coal withdrawals, a direct contrast to the outcome in Australia.

In summary, the "disorderly" transition in Australia has resulted in investment in flexible mid-merit generation of only 0.5 times the coal capacity withdrawal. The relative high price of gas and inherently uncertain policy environment have played a key role in this outcome. This can be contrasted with the U.S. where the ratio is 1.9 times of gas plant investment (1.4 times CCGT alone). These summary statistics are presented in Table 4.

Importantly, the high wholesale prices created by this "disorderly" transition have resulted in significant investment in new renewable energy. As at end 2017, around 4 GW of new capacity (mainly wind and solar) is under construction throughout the east-coast National Electricity Market. The projects and their cumulative capacity are presented in Fig. 3. Such investment has been incentivized by both high wholesale prices and the relatively robust price of Large-Scale Generation Certificates (LGCs) under Australia's 20% Renewable Energy Target.

But while there are significant investments being made in wind and solar, there has not been the same investment in new "firm" capacity

Table 3
New capacity and coal-fired capacity withdrawals in U.S.
Source: Simshauser (2017).

Year of Exit/Entry	Coal Retirements		Gas Plant Entry			Renewables Entry	
	No. of plant	Capacity (MW)	No. of plant	Capacity (MW)	CCGT[a] (MW)	No. of plant	Capacity (MW)
2005–2012	245	11,257	648	81,775	72,925	1500	57,449
2013+	384	50,367	241	36,183	14,490	2042	44,998
Total	629	61,624	889	117,958	87,416	3542	102,447
Av. Age		52 years					

Coal-fired generation closure – 18% of fleet.
[a] CCGT column is a subset of the total gas capacity column.

Table 4
Australian and U.S. investment ratios in gas/renewables relative to coal exit.
Source: Simshauser (2017).

	Coal exit	Average Exit Age	Gas Plant Entry Ratio	CCGT Component	Renewables Plant Entry Ratio
Australia	18%	42 years	1.6× coal exit	0.5× coal exit	0.9× coal exit
USA	18%	52 years	1.9× coal exit	1.4× coal exit	1.7× coal exit

that is equivalent to the thermal capacity being withdrawn. It is this lack of forthcoming investment in "firm" capacity that has created intense focus on the New South Wales market and the impending closure of the Liddell power station in 2022. While nearly 9000 MW of new gas-fired capacity has been added to the system since 2003, there have been concerns that this is not sufficient to ensure reliability given demand growth between 2003 and 2010, the existing withdrawal of around 5000 MW of coal-fired capacity through closures, and the impending closure of the Liddell power station in 2022.

3. Overview of the New South Wales electricity market

The New South Wales electricity market is a summer peaking system with baseload demand of around 5500 MW and peak demand of around 14,000 GW. The market is serviced by 10,160 MW of coal, 567 MW of CCGT (and equivalent plant) and 4236 MW of OCGT and hydro. The load duration curve for the FY17 period and a stylized representation of the generation mix is presented in Fig. 4.

In addition to climate change considerations, there are two key factors driving a shift in generation investment: declining energy demand, and a significant reduction in energy production costs of solar and wind technologies. Firstly, there has been a separation in the growth of underlying energy demand and peak demand. Peak demand has continued to grow while underlying energy demand has been declining since 2010. The Australian Energy Market Operator (AEMO) has forecast that annual energy demand will decline from 67,958 GWh in 2017 to 65,976 GWh in 2022. At the same time, peak demand is expected to remain at current levels or even increase marginally. In summary, the market requires less energy but the same capacity. This has obvious and non-trivial implications for the type of generation that is required to service the system.

The other key factor driving a shift in generation investment is the material reduction in capital costs for new solar and wind technologies. Appendix 1 provides a summary of key power plant parameters for various technologies in 2007, 2012, and 2017. Utilizing a standard power plant financial model (see Simshauser, 2017), an estimate of the fixed and variable costs of various technologies are presented in Fig. 5.

Fig. 5 demonstrates that the most economic form of *energy* production in Australia is now wind generation with a long-run marginal cost of around $60 per MWh. This is around 12% cheaper than black coal generation and around 22% cheaper than brown coal generation. Gas is significantly more expensive as a result of the factors discussed in the previous Section. In fact, at $8 per GJ fuel cost, a CCGT has a long-run marginal cost of $87.93 per MWh, around 31% more expensive than wind. Importantly, there is another key feature of wind and solar that has attracted investors. They are able to be installed in smaller,

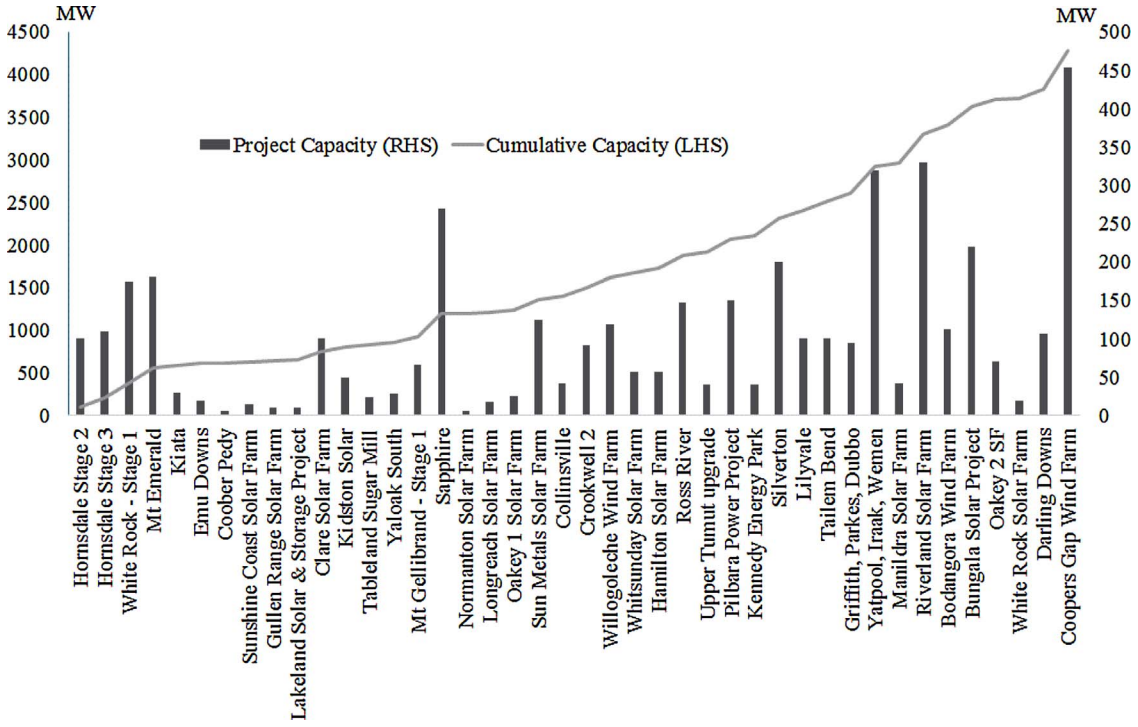

Fig. 3. Projects under construction and cumulative capacity in 2017.
Source: Compiled from industry sources.

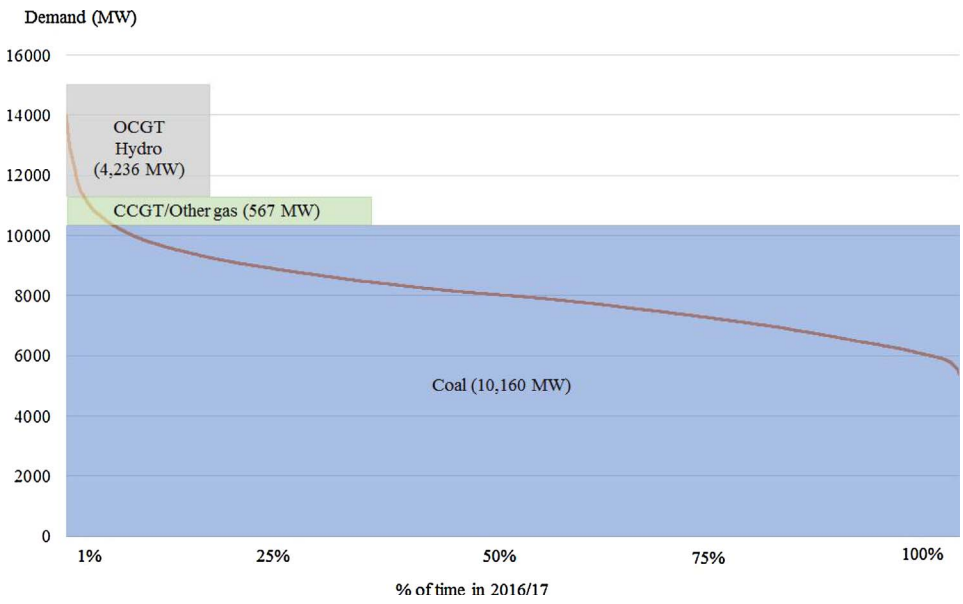

Fig. 4. New South Wales electricity market.
Source: AEMO data.

more modular formats than conventional thermal high-capacity-factor plant. This allows investment to be spread across technologies and regions providing some diversification of risk when compared to the minimum scale required to make a gas-fired or coal-fired project viable. Unsurprisingly, there is 1367 MW of existing and new solar and wind projects in the New South Wales electricity system.

The combination of stable or rising peak demand, declining underlying energy demand, and increased output from variable renewable generators has distinct implications for the type of investment required to replace the Liddell power station. The area under the load duration curve that needs to be served by "dispatchable" generation is decreasing as a result of falling energy demand and increased output from variable renewable resources. Given the same (or even an increase in) capacity is required but the amount of energy needed from "dispatchable" generation is lower, the type of plant required is likely to shift from inflexible coal plant to more "flexible" gas-fired plant, better suited to operating at a lower capacity factor. This is reinforced by the increasing need for plant to "complement" variable renewable resources when they are not producing due to a temporary lack of wind or solar resources. A stylised summary of these changing market dynamics is presented in Fig. 6, including the impact of closure of the Liddell power station (which reduces coal-fired generation to 8160 MW).

4. An optimal plant mix solution

Given the changing market dynamics outlined in the previous Section, an "optimal plant mix" can be used to determine the incremental investment required given the closure of the Liddell power station in 2022. Our optimal plant mix model is based upon Berrie (1967). The model is consistent with that outlined in Simshauser and

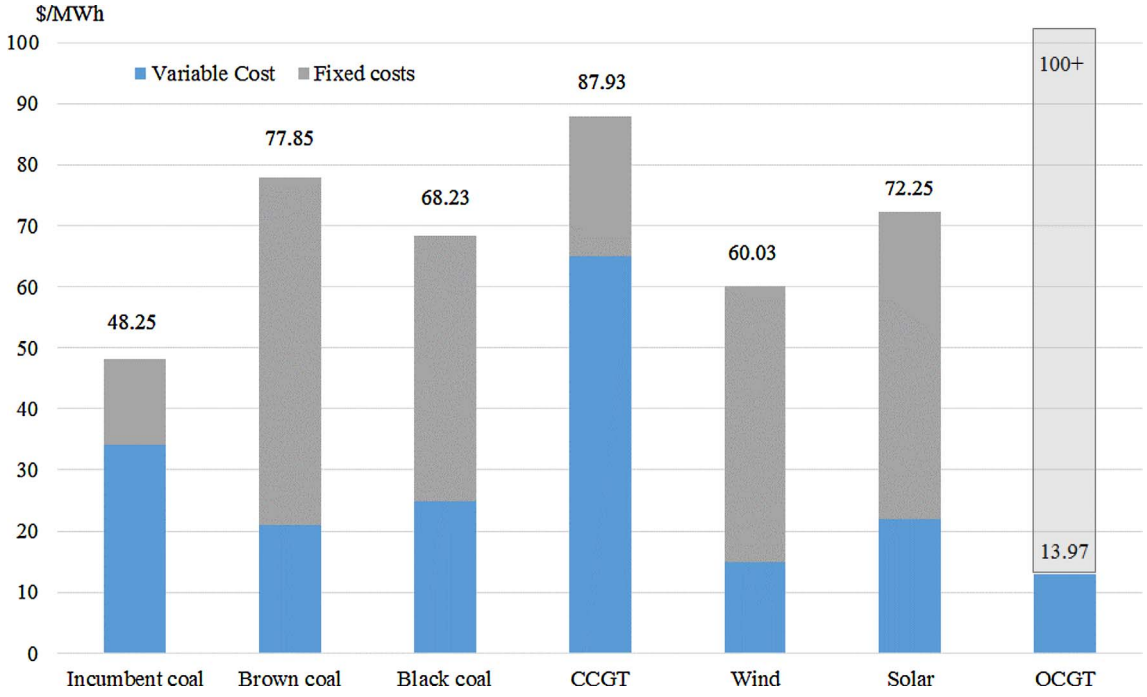

Fig. 5. Long-run marginal cost of *energy* for different generation technologies.
Source: Adapted from Simshauser (2017).

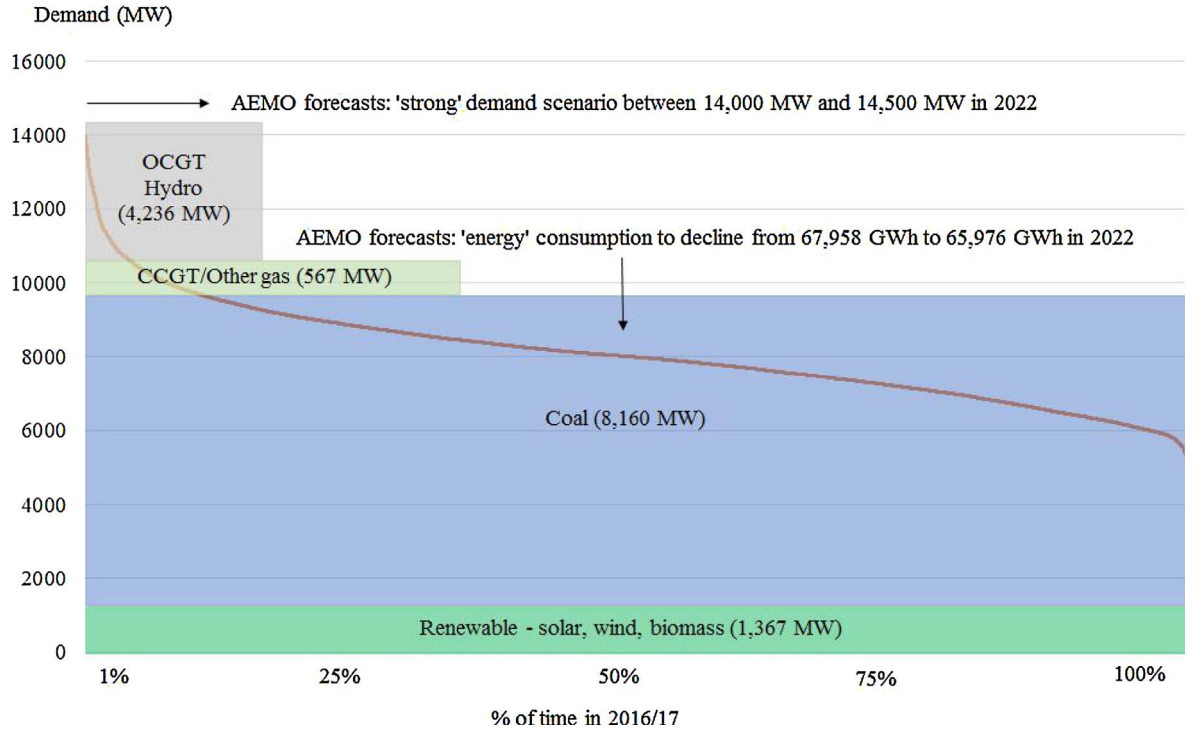

Fig. 6. Summary of the changing dynamics of the New South Wales electricity market. Source: Compiled from AEMO data.

Wild (2009) and so it is not reproduced here. In essence, the model utilizes the unique economics of three technologies that are "dispatchable":

- Generation plant with relatively high capital costs but low operating costs is used to meet baseload demand (demand that occurs for most of the time). Historically, black coal generation, which is slow to start or shut down, has been used to meet baseload demand in New South Wales. Such plant typically operates at a 75–90% capacity factor and is relatively inflexible.
- Intermediate demand (nominally the higher "daytime demand") is generally met by plant with medium capital and operating costs and flexible operating capacity (i.e. can be ramped up quickly). Combined cycle gas turbine (CCGT) plant is generally used to meet intermediate demand (assuming gas is available) and typically runs at an annual capacity factor of between 40 and 60%.
- Generation plant with relatively low capital costs but high operating costs is used to meet peak demand (demand that only occurs on the hottest and coldest days of the year, or during power system contingency conditions such as unexpected plant outages). Open cycle gas turbine (OCGT) plant, reciprocating engines or hydro generation, which can be ramped up very quickly, is used to meet peak demand and typically operates at annual capacity factors of between 5 and 30%.

An optimal plant mix is derived for the FY22 load curve based upon AEMO's assumptions outlined in the previous section. This optimal plant mix is then contrasted with existing supply (by plant type). Renewable generation is not characterized as baseload, intermediate, or peaking but is instead deducted from final demand to form a "residual load curve" in a manner consistent with Bushnell (2010) and Simshauser et al. (2011). The graphical representation of the "optimal mix" for 2022 is presented in Fig. 7.

The results of the optimal plant mix calculations are presented in Table 5. Given the reduction in energy demand and introduction of variable renewable resources, there is an overweighting of baseload capacity even after the withdrawal of the Liddell power station. That said, both intermediate and peaking generation are underweight with a total required deficit of capacity of 1023 MW. There are two clear conclusions that can be drawn from this analysis.[2]

- The market does not suit ongoing operation of the Liddell power station beyond 2022. Even after its withdrawal there is still a clear overweighting of baseload capacity. As such, it is a reasonable conclusion that investment in alternative capacity (given the significant capital expenditure associated with Liddell's ongoing operation beyond 2022[3]) would be a preferable solution.
- Increased peaking generation is required. Given the overweighting of baseload capacity approximately offsets the underweighting of intermediate capacity, the ongoing optimal investment is in peaking generation. Approximately 1000 MW of new fast-start capacity is needed.[4]

The optimal plant mix analysis is somewhat dependent upon the price of gas. There are a range of views about the future of gas prices in Australia. In this model, gas prices of $8 per GJ have been assumed for mid-merit CCGT plant. While the optimal plant mix analysis indicates that the overweighting of coal and underweighting of CCGT effectively balance each other out, gas is likely to play an important role moving forward. Assuming that Australia meets its COP21 commitments of a 26–28% reduction in greenhouse gas emissions by 2030 relative to 2005 levels, significant additional investment in renewable energy will be required. "Dispatchable" plant will be required to complement this increased variable renewable output but gas is preferable to coal due to its relatively quick start and "flexible" capabilities.

[2] This analysis ignores interconnector and reserve margin considerations. Reserve margins would increase the amount of peaking generation required by the system.

[3] AGL has disclosed that best estimates to date indicate capital expenditure of around $1 billion to extend the life of the Liddell plant for 5 years.

[4] It may be that alternatives to generation such as aggregated demand response are more economic than constructing and operating new peaking generation. This has been ignored in this analysis for simplicity.

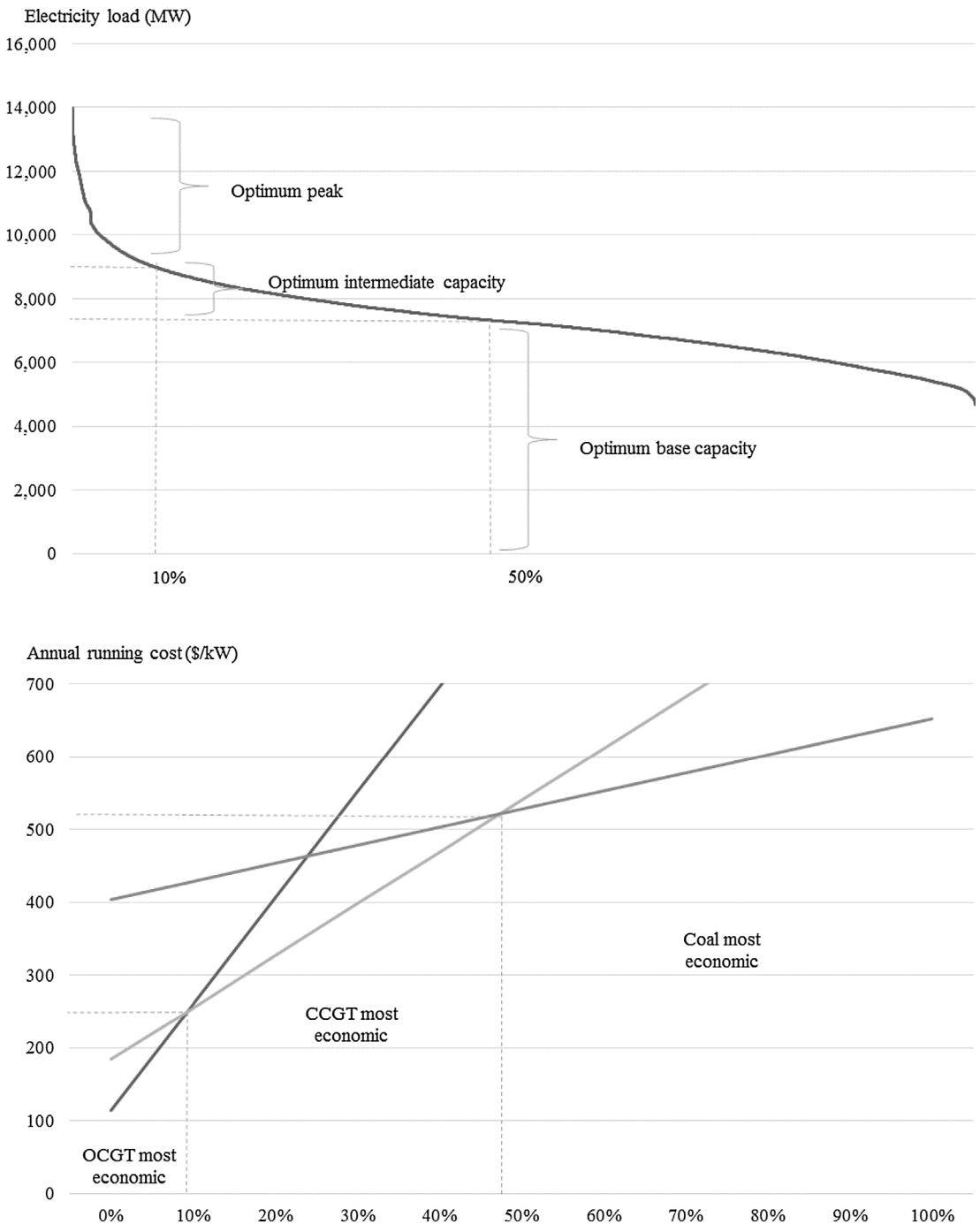

Fig. 7. Optimal plant mix calculations for 2022 load curve.

Table 5
Optimal plant mix results.

Category	Optimal	Actual (2022)[a]	Imbalance	Weighting
Baseload	7295	8160	865	overweight
Intermediate	1669	567	−1102	underweight
Peaking	5022	4236	−786	underweight
	13,986	12,963	−1023	

[a] This assumes no new investment apart from plant under construction. It also assumes Liddell power station is closed.

It is important that policymakers and the Australian electricity supply industry consider how best to ensure gas supply is sufficient to fuel increased utilisation of new and existing mid-merit gas plant. Credit Suisse (2017) has found that the most efficient economic solution would be to develop gas import infrastructure (such as floating storage regasification unit, or FSRU, technology). Such a development would ensure that the market price floor (created by LNG export capability) is also the market price cap. Gas import infrastructure would create a bidirectional export/import capability and would be likely to significantly improve market liquidity, price transparency, and the development of new financial hedging instruments in Australia's east-coast gas markets.

5. Other considerations

The analysis in the preceding section examines the core energy market dynamics of the New South Wales electricity system and an

Table 6
Other considerations relating to investment in generation infrastructure.

Issue	Extend Liddell/ Build Coal	New Renewables	New Gas Plant
Mitigates climate change risk	×	√	√
Consumer brand appeal	×	√	√
Employee health and safety	×	√	√
Mitigation of impacts on local community[a]	√	×	×

[a] This assumes that the community benefits from the economic activity associated with extending the operation of the plant. AGL has launched a 'Transition Alliance' with local community representatives to consider alternative uses of the site (see AGL, 2017).

optimal plant mix. However, there are a range of other considerations that investors are likely to have in relation to the appropriate suite of technologies that should be used to replace the Liddell power station. These include: mitigation of impacts on local community; customer and brand; employee health and safety, and most prominently climate change. A summary of these issues and the potential fit of the different investment options discussed in Section 4 is presented in Table 6.

Table 6 shows that across multiple other criteria, investment in new renewables and new gas plant is preferable to extending the operation of the existing Liddell power station or replacing it with new coal-fired generation. Extending the life of a 50-year-old power station or investing in new coal capacity is likely to be a difficult proposition to sell to consumers who increasingly are seeking innovative renewable solutions from their energy provider. It is also inherently incompatible with Australia's emission reduction obligations (see AGL, 2016 for more detailed modeling).

6. Concluding remarks

This article has considered the future of electricity generation in Australia with a focus on the case study of New South Wales. As a result of Australia having undergone a "disorderly" transition away from aging coal-fired generation with significant increases in wholesale electricity prices, there has been intense focus on the future of the Liddell power station. The analysis in this article finds that shifting market dynamics in relation to demand and technology costs results in the most economic new investment option being renewables for *energy* and gas-fired generation for *flexible, dispatchable capacity*. Extending the life of the Liddell power station beyond 2022 or investing in new coal-fired generation would provide *dispatchable* but not *flexible* generation. It would also be inconsistent with Australia's international obligations to reduce greenhouse gas emissions.

In the future, it may be that energy storage (through batteries, pumped hydro, or production of hydrogen utilizing renewable energy) is a better option than gas-fired generation. Given renewable penetration in the New South Wales market is not sufficient to meet minimum demand, there is little benefit to deploying energy storage. However, this could change as greater levels of investment in renewable energy may see renewable production capacity exceed minimum demand at some point in the future. At this time, storage would be a direct substitute for gas-fired generation.

It will be important for the Commonwealth and state governments to agree on a long-term and durable energy and climate change policy mechanism. If implemented in the right manner, the National Energy Guarantee could deliver on the objectives of reliability, affordability, and reduced greenhouse emissions. It is important that the policy incentivize investment in low-emissions electricity supply and ensure that generators and retailers support the forward derivatives market to ensure reliable supply and liquidity that facilitates ongoing retail market competition.

Appendix 1

Technology parameters in 2007, 2012 and 2017.
Source: Simshauser (2017).

Technology	Capex *kj* ($/kW)	Installed Capacity *USj* (MW)	Generating Units *ψOij* (MW)	Unit Heat Rate *HRj* (kJ/kWh)	Unit Fuel Cost *UFCj* ($/GJ)	Capacity Factor *ACFj* (%)	Fixed O&M Cost *FOMj* ($/MW/a)	Variable O&M *VOMj* ($/MWh)	Capital Works *CWj* (%)	Auxillary Load *xj* (%)	Carbon Intensity (t/MWh)
2007											
Inputs											
Black Coal	1,500	1,000	2	9,500	1.00	90%	48,000	1.00	0.25%	7.00%	0.86
Brown Coal	2,250	1,000	2	12,150	0.40	90%	55,000	1.30	0.25%	8.00%	1.10
CCGT	1,200	380	1	7,000	3.25	85%	10,000	3.00	0.05%	2.00%	0.63
Wind	2,100	200	100	–	–	37%	40,000	1.00	0.05%	2.00%	–
Solar PV	4,000	20	–	–	–	24%	62,000	–	0.05%	0.50%	–
2012											
Inputs											
Black Coal	2,250	1,000	2	9,000	1.25	90%	49,250	2.00	0.25%	7.10%	0.81
Brown Coal	3,000	1,000	2	11,613	0.40	90%	60,250	4.00	0.25%	9.60%	1.05
CCGT	1,250	380	1	6,965	5.50	85%	10,000	7.00	0.05%	3.00%	0.63
Wind	2,500	450	180	–	–	39%	45,000	1.00	0.05%	2.00%	–
Solar PV	3,500	100	–	–	–	28%	59,435		0.05%	0.50%	–
2017											
Inputs											
Black Coal	3,050	1,000	2	8,450	1.54	90%	50,500	4.00	0.25%	7.10%	0.76
Brown Coal	4,000	1,000	2	11,150	0.40	90%	65,500	5.00	0.25%	9.60%	1.01
CCGT	1,500	380	1	6,930	8.00	85%	10,000	7.00	0.05%	3.00%	0.63

Wind	1,787	450	118	–	–	41%	50,000	1.00	0.05%	2.00%	–
Solar PV	1,500	100	–	–	–	30%	56,870	–	0.05%	1.00%	–

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